POWER PLANT EFFICIENCY

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INTRODUCTION

The Energy Commission makes findings as to whether energy use by the East Altamont Energy Center (EAEC) will result in significant adverse impacts on the environment, as defined in the California Environmental Quality Act (CEQA). If the Energy Commission finds that the EAEC's consumption of energy creates a significant adverse impact, it must determine whether there are any feasible mitigation measures that could eliminate or minimize the impacts. In this analysis, staff addresses the issue of inefficient and unnecessary consumption of energy.

In order to support the Energy Commission's findings, this analysis will:

- determine whether the facility will likely present any adverse impacts upon energy resources;
- determine whether these adverse impacts are significant; and if so,
- determine whether feasible mitigation measures exist that would eliminate the adverse impacts, or reduce them to a level of insignificance.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

No federal laws apply to the efficiency of this project.

STATE

California Environmental Quality Act Guidelines

CEQA Guidelines state that the environmental analysis "…shall describe feasible measures which could minimize significant adverse impacts, including where relevant, inefficient and unnecessary consumption of energy" (Cal. Code Regs., tit. 14, § 15126.4(a)(1)). Appendix F of the Guidelines further suggests consideration of such factors as the project's energy requirements and energy use efficiency; its effects on local and regional energy supplies and energy resources; its requirements for additional energy supply capacity; its compliance with existing energy standards; and any alternatives that could reduce wasteful, inefficient and unnecessary consumption of energy (Cal. Code regs., tit. 14, § 15000 et seq., Appendix F).

LOCAL

No local ordinances apply to power plant efficiency.

SETTING

The applicant proposes to construct and operate the 1,100 MW (nominal gross output) merchant EAEC power plant to sell energy to the power market or directly to customers via short- and mid-term contracts (EAEC 2001a, AFC §§ 1.1, 2.2.16, 10.2.2, 10.3). (Note that this nominal rating is an approximate value based upon preliminary design information and generating equipment manufacturers' projected performance with the plant operating at full load with maximum HRSG duct firing on a cold day.) The AFC is not specific as to whether the plant is intended to supply baseload, load-following and/or peaking power, but in response to Energy Commission staff's queries, the applicant later clarified that the plant will provide both baseload and peaking power (EAEC 2001hh). Although the AFC described the EAEC as an 1,100 MW (nominal) combined cycle power plant, the project is actually an 820 MW combined cycle baseload power plant (at average ambient conditions), with an additional 238 to 269 MW of peaking capacity (depending on the ambient conditions) provided by large duct burners and a large steam turbine generator (EAEC 2001hh). The applicant envisions operating the plant up to 8,760 hours per year with the incremental peaking capacity operated for up to 5,080 hours per year (EAEC 2002a).

The EAEC will consist of three General Electric PG7251(FB) combustion turbine generators with inlet air fogging systems and steam injection producing approximately 180 MW each at baseload conditions (average ambient conditions with no inlet air fogging or steam injection), three multi-pressure heat recovery steam generators (HRSGs) with duct burners, and one three-pressure, reheat, condensing steam turbine generator producing a maximum of 550 MW (average ambient conditions), arranged in a three-on-one combined cycle train, totaling approximately 1,090 MW at average ambient conditions. The gas turbines and HRSGs will be equipped with dry low-NOx combustors and selective catalytic reduction to control air emissions (EAEC 2001a, AFC §§ 1.1, 2.2.2, 2.2.3, 2.2.4, 2.2.4.1, 2.2.4.2, 2.2.4.3, 2.2.4.4, 2.4.2.1, 10.2.2; EAEC 2001ee). Natural gas will be delivered by the existing Pacific Gas & Electric (PG&E) backbone gas transmission Line 401 via a new 20-inch diameter 1.8-mile natural gas pipeline (EAEC 2001a, AFC §§ 1.1, 2.1, 2.4.3, 6.0, 6.1, 10.2.1; EAEC 2002n, p. 2).

ANALYSIS

ADVERSE IMPACTS ON ENERGY RESOURCES

The inefficient and unnecessary consumption of energy, in the form of non-renewable fuels such as natural gas and oil, constitutes an adverse environmental impact. An adverse impact can be considered significant if it results in:

- adverse effects on local and regional energy supplies and energy resources;
- a requirement for additional energy supply capacity;
- noncompliance with existing energy standards; or
- the wasteful, inefficient and unnecessary consumption of fuel or energy.

Project Energy Requirements And Energy Use Efficiency

Any power plant large enough to fall under Energy Commission siting jurisdiction will consume large amounts of energy. The EAEC will burn natural gas at a nominal rate of 120 billion Btu per day lower heating value (LHV) (EAEC 2001ee). This is a substantial rate of energy consumption and holds the potential to impact energy supplies. Under expected project conditions, electricity will be generated at a baseload (820 MW) efficiency of approximately 56 percent LHV, and additional peaking capacity (up to 269 MW) at an incremental efficiency of 41 to 42 percent LHV, yielding a full load (up to 1,090 MW) efficiency ranging from 51.5 percent to 52 percent LHV (EAEC 2001a, AFC Figures 2.2-4a & 2.2-4b; EAEC 2001ee; EAEC 2001hh). Compare this to the average fuel efficiency of a typical 1960s-era utility company baseload power plant at approximately 35 percent LHV.

Adverse Effects On Energy Supplies And Resources

The applicant has described its sources of supply of natural gas for the project (EAEC 2001a, AFC §§ 1.1, 1.3.2, 2.1, 2.4.3, 6.0, 10.2.1). Natural gas for the EAEC will be supplied from the existing PG&E system via PG&E's Line 401 at the Bethany compressor station, about 1.4 miles west of the EAEC site. Line 401 is capable of delivering the required quantity of gas to the EAEC. Furthermore, the PG&E gas supply infrastructure is extensive, offering access to vast reserves of gas from Canada and the Southwest. This source represents far more gas than would be required for a project this size. It is therefore highly unlikely that the project could pose a substantial increase in demand for natural gas in California.

Additional Energy Supply Requirements

Natural gas fuel will be supplied to the project by PG&E's existing line 401 via a new 20-inch diameter pipeline (EAEC 2001a, AFC §§ 1.1, 1.3.2, 2.1, 2.4.3, 6.0, 6.1, 10.2.1; EAEC 2002n, p. 2). This line should provide adequate access to natural gas fuel. There is no real likelihood that the EAEC will require the development of additional energy supply capacity.

Compliance With Energy Standards

No standards apply to the efficiency of the EAEC or other non-cogeneration projects.

Alternatives To Reduce Wasteful, Inefficient And Unnecessary Energy Consumption

The EAEC could be deemed to create significant adverse impacts on energy resources if alternatives existed that would reduce the project's use of fuel. Evaluation of alternatives to the project that could reduce wasteful, inefficient or unnecessary energy consumption first requires examination of the project's energy consumption. Project fuel efficiency, and therefore its rate of energy consumption, is determined by the configuration of the power producing system and by the selection of equipment used to generate power.

Project Configuration

The EAEC will be configured as a combined cycle power plant augmented by duct burners. In a combined cycle system, electricity is generated by three gas turbines, and additionally by a steam turbine that operates on heat energy recuperated from the gas turbines' exhaust (EAEC 2001a, AFC §§ 1.1, 2.2.2, 2.2.3, 2.2.4). By recovering this heat, which would otherwise be lost up the exhaust stacks, the efficiency of any combined cycle power plant is increased considerably from that of either gas turbines or steam turbines operating alone. Such a configuration is well suited to the large, steady loads met by a baseload plant, intended to supply energy efficiently for long periods of time.

Duct Burners

While duct burners are commonly employed in combined cycle power plants, the EAEC presents a new approach to the use of duct burners. As the gas turbine's hot exhaust gases flow into the HRSG through the transition duct, a nozzle arrangement injects more natural gas fuel into the gas stream. The additional fuel burns, adding heat to the gas stream. This increased heat can serve several purposes. It ensures that the steam produced for the steam turbine is sufficiently hot to provide optimum steam turbine performance; it can produce additional steam for injection into the gas turbine, increasing the gas turbine's power output; and it can produce still more steam to drive an even larger steam turbine. Another valuable feature of duct burners is their contribution to flexibility; while a modern clean-burning combined cycle operates optimally at steady (baseload) output, the duct burner allows the unit to load follow, throttling up and down in response to system load changes. In the EAEC, the duct burners will perform all these tasks.

In a common combined cycle power plant (represented by Calpine's Metcalf Energy Center project), a pair of F-class gas turbine generators produce 544 MW; the balance of the plant's 600 MW output, or 56 MW, is provided by the duct burners. Thus, about nine percent of the plant's total power output is generated by heat from the duct burners.

Another example of duct burning is Calpine's Delta Energy Center, in which three F-class gas turbine generators produce 816 MW of the plant's 880 MW capacity. The balance, 64 MW, is provided by heat from the duct burners; this represents seven percent of the plant's total output.

The EAEC, also a Calpine project, represents a wide departure from this norm. The unique feature of the EAEC is that the duct burners are much larger than normal. While complete data were not made available to Energy Commission staff for a thorough numerical analysis of project efficiency, the information provided by the applicant demonstrates the following. Maximum power output from the plant will be 1,087 MW (at 45°F ambient, with maximum inlet air fogging, duct burning and steam injection). Subtracting the power output of the three gas turbine generators, or 820 MW (EAEC 2001a, AFC Figures 2.2-4a and 2.2-4b; EAEC 2001e, page 10; EAEC 2001ee; EAEC 2001hh) yields 267 MW to be provided by heat from the duct burners. This represents 25 percent of total power output.

According to data provided by the applicant, while the fuel efficiency of the plant with the duct burners not operating will be 56 percent LHV (representing the state of the art), the fuel efficiency of the plant with the duct burners operating will be 51.5 to 52 percent (LHV), representing a drop in fuel efficiency of four percentage points.

It should be noted that this reliance on large duct burners appears to be the beginning of a trend. Calpine has since filed AFCs for the Inland Empire Energy Center (01-AFC-17) and the San Joaquin Valley Energy Center (formerly the Central Valley Energy Center) (01-AFC-22), which both employ these burners. The chief benefits of this configuration involve capital investment; the developer can save substantial money in building the project compared to a more typical four-on-two combined cycle arrangement. Energy Commission staff fully expects Calpine's competitors to consider following this lead in their future designs.

Alternative to Duct Burners

The operating flexibility afforded by duct burning in the EAEC could alternatively be supplied by a three-on-one non-duct fired combined cycle plant of 820 MW, plus several smaller peaking plants generating 267 MW, totaling 1,087 MW. The most effective means of achieving this peaking capacity would be with six GE LM6000 Enhanced SPRINT gas turbine generators, rated at 48 MW each for a total of 288 MW. The LM6000 SPRINT offers the best fuel efficiency and air emissions performance of any such machine available today. The claimed efficiency of these machines is 39.6 percent LHV (GTW 2000).

If the EAEC were operated without duct burning, and six LM6000 SPRINT peakers were operated in conjunction to provide 1,108 MW total, the resulting net fuel efficiency would be 51 percent LHV. This does not quite equal the 51.5 to 52 percent range projected for the EAEC with duct burning, and offers no advantage in fuel efficiency or air emissions performance. The LM6000 peaker alternative would also involve considerable additional expense and complication in building, operating and maintaining the facility.

Equipment Selection

Modern gas turbines embody the most fuel-efficient electric generating technology available today. Their higher pressure ratio and firing temperature offer higher efficiencies than conventional turbines. They offer proven technology with numerous installations and extensive run time in commercial operation. Emission levels are also proven, and guaranteed emission levels have been reduced based on operational experience and design optimization by the manufacturers. The F-class gas turbines to be employed in the EAEC represent some of the most modern and efficient such machines now available. The applicant will employ three General Electric PG7251(FB) (Frame 7FB) gas turbine generators in a three-on-one combined cycle power train (EAEC 2001a, AFC §§ 1.1, 2.2.2, 2.2.4, 2.2.4.1). This configuration is nominally rated at approximately 850 MW and 57.5 percent efficiency LHV at ISO[1] conditions (GTW 2000).

One possible alternative machine is the Alstom Power ABB KA24, a gas turbine nominally rated in a three-on-three configuration at 780 MW and 56.5 percent efficiency LHV at ISO conditions (GTW 2000).

[1] International Standards Organization standard conditions are 59°F (15°C), 60 percent relative humidity, and sea level pressure (29.92 in. Hg).

Another alternative is the Siemens-Westinghouse 501FD (W501FD), nominally rated in three-on-one configuration at approximately 825 MW and 55.8 percent efficiency LHV at ISO conditions (GTW 2000).

Still another alternative is the General Electric GE Frame 7FA, predecessor to the Frame 7FB, nominally rated in three-on-one configuration at approximately 792 MW and 56.5 percent efficiency LHV at ISO conditions (GTW 2000). Except for slightly lower pressure ratio and firing temperature, resulting in a slightly lower efficiency and somewhat lower combined cycle output, this machine is identical to the Frame 7FB.

Any differences among the GE 7FA, ABB KA24, and W501FD in actual operating efficiency would be insignificant. The GE 7FB selected for this project, however, is measurably more efficient, by about 1.5 percentage points.

Efficiency Of Alternatives To The Project

The project objectives include competing as a merchant plant, generating energy for sale on the spot market, and directly to customers via short- and mid-term contracts (EAEC 2001a, AFC §§ 1.1, 2.2.16, 9.5, 10.2.2, 10.3).

Alternative Generating Technologies

Alternative generating technologies for the EAEC are considered in the AFC (EAEC 2001a, AFC §§ 1.4, 9.5). Conventional boiler and steam turbine, simple cycle combustion turbine, conventional combined cycle, Kalina combined cycle, advanced combustion turbines, natural gas, coal, oil, solar, wind, hydroelectric, biomass, geothermal, nuclear, municipal solid waste and ocean energy conversion technologies are all considered. Given the project objectives, location, and air pollution control requirements, staff agrees with the applicant that only natural gas-burning technologies are feasible. Western has determined that none of these generating technology alternatives, other than the proposed action, are consistent with Western's purposes and need.

Natural Gas-Burning Technologies

Fuel consumption is one of the most important economic factors in selecting an electric generator; fuel typically accounts for over two-thirds of the total operating costs of a fossil fuel-fired power plant (Power 1994). Under a competitive power market system, where operating costs are critical in determining the competitiveness and profitability of a power plant, the plant owner is strongly motivated to purchase fuel-efficient machinery.

Capital cost is also important in selecting generating machinery. Recent progress in the development of large, stationary gas turbines, aided by the incorporation into these machines of technological advances made in the development of aircraft (jet) engines, has created a situation in which several large manufacturers compete vigorously to sell their machines. This, combined with the cost advantages of assembly line manufacturing, has driven down the prices of these machines. Thus, the power plant developer can purchase a turbine generator that not only offers the lowest available fuel costs, but at the same time sells for the lowest per-kilowatt capital cost.

One possible alternative to an F-class gas turbine is a G-class machine, such as the Siemens-Westinghouse 501G gas turbine generator, which employs partial steam cooling to allow slightly higher firing temperatures. This results in a combined cycle rating of 365 MW at 58.0 percent LHV at ISO conditions (GTW 2000). The 501G is still relatively new; the first such machines only recently began operation at the McIntosh plant in Florida owned by Lakeland Electric and Water, and at PG&E National Energy's Millennium plant in Charlton, Massachusetts (GTW 2001, p. 45). Given the minor efficiency improvement promised by the G-class turbine and the lack of a proven track record for the 501G, the applicant's decision to purchase F-class machines is a reasonable one.

Another possible alternative to the F-class gas turbine is an H-class machine. An example is the General Electric S107H, with rated power output of 400 MW and a claimed fuel efficiency of 60 percent LHV at ISO conditions (GTW 2000). This high efficiency is achieved through a higher pressure ratio and higher firing temperature, made possible by cooling the initial turbine stages with steam instead of air. This first Frame 7H application is not expected to enter service until the end of 2003 at Sithe Energy's Independence Station in Scriba, New York (GTW 2001, p. 28). Given the lack of proven performance, staff agrees with the applicant's decision to employ F-class machines.

Inlet Air Cooling

A further choice of alternatives involves the selection of gas turbine inlet air cooling methods. The two commonly used techniques are the evaporative cooler or fogger, and the chiller; both devices increase power output by cooling the gas turbine inlet air. A mechanical chiller can offer greater power output than the evaporative cooler on hot, humid days, but consumes electric power to operate its refrigeration process, thus slightly reducing overall net power output and, thus, overall efficiency. An absorption chiller uses less electric power, but necessitates the use of a substantial inventory of ammonia. An evaporative cooler or a fogger boosts power output best on dry days; it uses less electric power than a mechanical chiller, possibly yielding slightly higher operating efficiency. The difference in efficiency among these techniques is relatively insignificant.

The applicant proposes to employ inlet air fogging (EAEC 2001a, AFC §§ 2.2.2, 2.2.4.1). Given the climate at the project site and the relative lack of clear superiority of one system over the other, staff agrees that the applicant's approach will yield no significant adverse energy impacts.

Condenser Cooling Technology

The EAEC is proposed with an evaporative (wet) cooling system to cool the steam turbine's condenser. In California's arid climate, wet cooling typically results in the greatest generating efficiency. In response to concerns over the prodigious consumption of water engendered by a wet cooling system, an analysis was made of an alternative cooling system, a dry cooling system incorporating an air-cooled condenser (EAEC 2001p). If such a system were incorporated into the project, overall annual fuel efficiency might be expected to drop as much as two percentage points,[2] and power output on a hot day, under full peaking output, may drop about 46.4 MW (EAEC 2001p). While this is a measurable degradation in power output and fuel efficiency, staff believes that it could be justified by the significant savings in water consumption. (Note that the applicant estimates potential revenue losses approaching $10 million per year if dry cooling is employed (EAEC 2002a). Staff does not purport to address the economics of a switch to dry cooling.) From an efficiency standpoint, then, staff regards the use of dry cooling as a justifiable modification. Western, on the other hand, has determined that no condenser cooling alternatives, other than that proposed, are consistent with Western's purposes and need.

In conclusion, the project configuration (combined cycle) and generating equipment (F-class gas turbines) chosen appear to represent the most efficient feasible combination to satisfy the project objectives. There are no feasible alternatives that could significantly reduce energy consumption.

CUMULATIVE IMPACTS

There are currently two nearby power plant projects that hold the potential for cumulative energy consumption impacts when aggregated with the project. GWF Energy LLC has filed an AFC with the Energy Commission for the 169 MW Tracy Peaker Plant (01-AFC-16), and Midway Power, LLC (now FPL) recently filed an AFC for the 1,120 MW Tesla Power Plant (01-AFC-21). Staff knows of no other projects that could result in cumulative energy impacts. Cumulative impacts of energy consumption could exist if the supply of natural gas fuel were jeopardized by the aggregation of these projects. Based on the robust nature of the natural gas supply infrastructure in California, and in this region, staff deems it highly unlikely that this will be the case.

Staff believes that construction and operation of the project will not bring about indirect impacts, in the form of additional fuel consumption, that would not have occurred but for the project. The older, less efficient power plants consume more natural gas to operate than the new, more efficient plants such as the EAEC. Since natural gas will be burned by the power plants that are most competitive on the spot market, the most efficient plants will run the most. Operating in baseload mode, the high efficiency of the proposed EAEC should allow it to compete very favorably, running at a high capacity factor, replacing less efficient power generating plants in the market, and therefore not impacting or even reducing the cumulative amount of natural gas consumed for power generation. Operating in peaking mode, the EAEC's fuel efficiency compares favorably to alternative peaking plants, and would therefore have no indirect impact on fuel consumption.

FACILITY CLOSURE

Closure of the facility, whether planned or unplanned, will not influence, nor will it be influenced by, project efficiency. Any efficiency impacts due to closure of the project would be on the electric system as a whole. Yet the vast size of the electric system serving California, the number of generating plants offering to sell power into it, and the

[2] This is the figure estimated for the Sutter Power Project (97-AFC-2).

existence of the California Independent System Operator to ensure the efficient management of the system, all lend assurance that closure of this facility will not produce significant adverse impacts on efficiency.

CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS

The project, if constructed and operated as proposed, would generate a nominal 820 MW of baseload electric power at an overall fuel efficiency around 56 percent LHV, and up to 269 MW of peaking power at an efficiency of around 41 to 42 percent LHV, yielding a total nominal output of 1,100 MW at an overall fuel efficiency around 51.5 to 52 percent LHV. As proposed, the EAEC will consume substantial amounts of energy at efficiency levels comparable to a typical combined cycle baseload power plant in conjunction with a typical peaking plant. However, it will not create significant adverse effects on energy supplies or resources, nor will it require additional sources of energy supply or consume energy in a wasteful or inefficient manner. Staff therefore concludes that the project would present no significant adverse impacts upon energy resources.

No energy standards apply to the project. No cumulative impacts on energy resources are likely. Facility closure would not likely present significant impacts on electric system efficiency.

RECOMMENDATION

From the standpoint of efficiency, staff believes the EAEC can be certified. No Conditions of Certification are proposed.

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